The Public Utility Commission of Texas (commission) adopts new §25.211 relating to Interconnection of Distributed Generation (DG) and §25.212 relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation with changes to the proposed text as published in the September 24, 1999 issue of the *Texas Register* (24 TexReg 8011). This section was adopted under Project Number 21220. The commission began an investigation into distributed generation in 1998 as part of Project Number 19827, *Investigation into the Adequacy of Capacity for 1999 and 2000 Peak Periods in Texas*. In part, the commission initiated this project because it was interested in utilizing distributed generation (DG) as a beneficial resource to help meet the State's growing capacity shortfall during the summer months of 1999 and 2000. As part of this project, a task force was formed to develop interconnection guidelines for distributed generation. On February 4, 1999, the commission adopted interconnection guidelines for distributed generation and requested that staff continue its investigation of distributed resources.

In adopting this rule, the commission's objectives are to clearly state the terms and conditions that govern the connection and operation of small power generation and to establish technical requirements to promote the safe and reliable operation of distributed generation resources, while the customer is connected to both its own distributed generation facility and the utility distribution system (referred to as parallel operation). Implementation of these rules (1) promotes the use of distributed resources in order to provide electric system benefits during periods of capacity constraints; (2) enhances both the reliability of electric service and economic efficiency in the production and consumption of electricity; and (3) provides customers greater opportunities to control the price and quality of electricity within their facilities.

Senate Bill 7 (SB 7), Act of May 21, 1999, 76th Legislature, Regular Session, chapter 405, 1999 Texas Session Law Service 2543, 2561 (Vernon) (to be codified as an amendment to the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §39.101(b)(3)) now entitles all Texas electric customers to access on-site distributed generation. Project Number 21220 was established to implement this provision. On July 21, 1999 staff held a workshop to begin the evaluation of issues related to distributed generation. During this workshop three sub-groups were formed relating to: 1) technical standards, 2) standard interconnection agreement, and 3) tariff and policy issues. The rules reflect the work products of these three subgroups. At an open meeting on September 9, 1999, the commission voted to publish a rule for comment in the *Texas Register*. On October 14, 15, and 19, 1999, a total of 11 interested parties filed comments on the proposal. On October 25, 1999, commission staff held a public hearing pursuant to §2001.029 of the Administrative Procedure Act. Thirty-four parties attended the public hearing, of which six provided comments that either addressed provisions set forth in the proposed sections, replied to written comments from other parties, or both. The parties represented at the public hearing included: the Office of the Attorney General (OAG), Enron, El Paso Electric (EPE), Entergy Gulf States (EGS), Texas-New Mexico Power Company (TNMP), Automatic Switch Company (Automatic Switch), Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities Company, which are the Texas electric operating companies of Central and Southwest Corporation (collectively, CSW), TXU Electric Company (TXU), Leroy Brown (independent consultant), Brazos Electric Power Company (Brazos), NewEnergy Texas (NewEnergy), the Distributed Generation Coalition (DGC) representing AlliedSignal Power Systems Inc., Capstone Turbine Corporation, El Paso Energy Corporation, NewEnergy Texas, L.L.C., and Sonat Power Systems Inc., Southwestern Public Service Company (SPS), Duke Solar, Reliant Energy (Reliant), Austin Energy, Engine World Inc., Schumate & Associates, Public Citizen, Fowler Energy, El Paso Energy, and Texas Renewable Energy Industries Association (TREIA).

The following parties filed initial comments in this proceeding: CSW, DGC, EPE, EGS, Fowler Energy, Reliant, Sonat, SPS, TNMP, Automatic Switch, and TXU. Additionally, the following parties provided oral comments at the October 25, 1999 public hearing: NewEnergy, DGC, TREIA, Public Citizen, and TXU.

DGC applauded the commission's work to eliminate historical barriers to DG technologies, stating that no other State has removed the barriers to DG as thoroughly as Texas will through this rulemaking. Fowler Energy supported the new rule in its current form, stating that this rule has great value to Texas electric consumers and it will foster growth and opportunity in the growing small-scale DG market. Sonat applauded the commission's efforts to facilitate DG in Texas. This company explained that fair and equitable interconnection requirements that safeguard the utility distribution system and afford customers new avenues for obtaining peaking services or competitive alternatives to traditional utility service will provide consumers with the best electric service technologically available at the lowest possible cost. While Reliant noted that the company has some operational and associated cost concerns regarding additional DG operating on a system that was originally designed as a radial system, Reliant supported the commission's efforts to facilitate the provisions in SB 7 for DG. Reliant concluded that it recognizes the challenges and welcomes the opportunity to transform its distribution system to accommodate industry restructuring in the new millennium. TXU generally commented that the traditional radial design and function of the electric utility distribution system will change with the eventual widespread implementation of DG because the direction of electrical flow along a feeder will become more dynamic. TXU further explained that the distribution system will become a complicated network system–no longer strictly radial–of sources and loads requiring new methods of analysis and operation. The company concluded that this new type of operation will likely result in increased costs in order to continue to provide reliable and safe electric service. TXU stated that the company recognizes that increasing amounts of DG will be placed on the distribution system and submitted that the commission and DG owners must recognize that this new network configuration of the distribution system will either increase distribution system operations and maintenance costs or result in lower reliability, or, possibly, both.

Comments on specific questions in the preamble to the proposed rule

In the preamble, the commission posed the following series of questions related to the necessity of conducting pre-interconnection studies for distributed generation units. Parties were asked to describe the differences between and applicability of service studies, coordination studies, and utility system impact studies as they relate to requests for interconnecting distributed generation and to state whether it is always necessary to conduct pre-interconnection studies for DG units. They were also asked to describe the components of an interconnection study, explain why each of these study components is necessary, and comment on whether an independent third party could conduct the studies.

DGC, CSW, EGS, Reliant, TNMP, and TXU described the differences between and applicability of a service study, coordination study, and a utility system impact study. With respect to service studies, these parties generally agreed that a service study is used to ascertain the method and voltage for providing service to a customer and that these studies vary in scope. These parties noted that a service study generally includes an inspection and engineering analysis of the facilities connecting the distributed generator and the utility. Reliant commented that it is also necessary to review the existing load and determine the size of the generator and transformer. Reliant clarified that the location of distributed generators must be known and must be entered into a utility's mapping system and databases for the utility's dispatching operations because the utility is responsible for tracking every distributed generator. TNMP commented that the service study would take into account any unique circumstances associated with the new generator or the electric system at the point of interconnection. TXU stated that a service study is necessary to determine the utility additions necessary to serve the customer's load and clarified that the study should consider the size, type, and location of the load on the distribution feeder and determine the selection of the size of the transformers, conductors, meter and other facilities necessary to serve the customer's load.

DGC, EGS, CSW, Reliant, TNMP, and TXU all provided slightly different definitions of a coordination study. DGC commented that a coordination study is used to determine whether the relays or voltage taps on the grid are set properly to handle the change in circumstances. DGC clarified that these studies are sometimes required by utilities when new load enters the system and that, in this instance, customers generally are not charged for these studies.

EGS defined a coordination study as an engineering study that determines whether the presence of the DG unit at a particular location would interfere with the protective fusing and relaying on either the transmission or distribution system. The company also stated that a DG unit of 50 kilowatts (kW) or less would be unlikely to cause coordination problems and therefore for the first one or two of these additions to a feeder, a study may not be necessary. However, EGS also clarified that multiple units on a typical feeder could cause coordination problems.

CSW commented that a coordination study is a comprehensive evaluation of all elements that may impact the safe and reliable operation of the interconnection. CSW provided examples of tasks included in a coordination study that included analyzing the available fault currents at various locations along the distribution circuit under differing conditions and determining the proper type and settings for all protective devices. CSW pointed out that service and coordination studies are generally combined into a single effort and generically referred to as an "Interconnection Coordination Study". CSW proposed changing the language in §25.211(g) to reflect this practice.

Reliant stated that coordination studies are needed for larger generators. Reliant explained that generators over 500 kilovolt amperes (KVA) require a fuse coordination study because they will have a significant fault current contribution that can cause miscoordination of upstream fuses. Reliant also noted that transfer trip studies are necessary for generators over 2,000 KVA to make sure that they trip quickly in the event of a line fault and also help the generator avoid false trips.

TXU commented that a coordination study verifies that the distribution feeder is adequately protected to ensure that the system is safe and provides reliable service. TXU explained that all protection devices within the vicinity of the customer's load must be evaluated, including substation breakers, line reclosers, and line fuses. Each device must be able to carry the required load but, at the same time, operate to clear any faults on the utility system that would affect either reliability or the safety of the public and utility personnel. TXU opined that a detailed coordination study is always necessary and DG greatly increases the complexity of the coordination study because DG is responsible for 1) a new source in the feeder at the customer's location, 2) the potential of reverse current flow in sections of the feeder, and 3) an increase in the available fault current. TXU also pointed out that this study is needed irrespective of whether the unit is exporting power into the utility's system, adding that, if the DG is capable of exporting more than one megawatt (MW) of electricity adjacent feeders may need to be evaluated for possible upgrades. TXU concluded that an in-depth study is therefore required to determine whether new coordination devices are necessary and whether existing coordination should be changed.

TNMP commented that an impact study examines the distributed generator's effect on the operation of the specific feeder it is on and subsequent impacts to other feeders interconnected with that feeder. TNMP explained that such a study would also determine any overloaded conductors, transformers, or other devices associated with the new generator addition and determine changes to the system needed to correct any such problems.

CSW stated that the utility system impact study determines the thermal loading and voltage impact on the utility's existing distribution system resulting from the interconnection of the DG. CSW provided examples of tasks necessary to complete an impact study that included reviewing and evaluating current and projected load flows, voltage profiles, voltage and reactive equipment needs, distribution system losses, optimal circuit configurations, and impact on future plans.

DGC commented that a utility system impact study is performed to determine the fault current contributions to the grid and explained that the fault current impact for smaller systems is negligible.

EGS commented that a utility system impact study encompasses a number of different engineering studies, explaining that the minimum requirement is a snapshot of the distribution system that is modeled in software with the proposed DG in place. EGS clarified that this snapshot determines whether the feeder, in its present configuration, will be able to support the DG unit without reliability problems or interruptions in service to customers. The company further explained that a transient analysis also will be required to determine the potential for stability problems as the number of units on a feeder increases; the grid will collect and distribute power, not just pass the power from the transmission grid through to the end-use customer. EGS pointed out that these same types of studies are also required for the transmission system if energy can flow back to the substation and onto the transmission grid.

TXU commented that an impact study determines the effect of the addition of a customer's load on the operation of the system and the impact on other customers connected to the distribution system. TXU explained that, in most cases, with the addition of load to the utility system, there is little impact to either the operation of the system or to other customers. The company submitted that a more extensive study is required when the addition of load is such that it may affect other customers or the operation of the system. TXU also noted that, in the case of DG, there is almost always an impact to both the operation of the system as well as to other customers and therefore a study is necessary regardless of whether the DG is exporting power.

Reliant commented that a load flow study that will check circuit loading and voltage drops is needed for generators over 500 KVA. Reliant pointed out that this is consistent with Reliant Energy's guidelines for reviewing all new loads over 500 KVA. Reliant explained that loads and generators over 500 KVA are big enough to have an impact on the loading and voltage on a circuit, and this impact needs to be studied. The company also stated that a harmonics study is needed for inverters over 500 KVA; even though inverters are required to meet the Institute of Electrical and Electronics Engineers (IEEE) 519 standard for harmonics, inverters of this size can have a serious impact on the harmonic interaction with distribution capacitors. Reliant also mentioned that DG installation on a network requires studies to modify the service arrangement to either a radial configuration or a configuration that has breakers and relays analogous to that of a transmission network.

With respect to the necessity of conducting pre-interconnection studies, CSW, EGS, Reliant, TXU, TNMP, and SPS generally commented that some type of study is needed for all interconnection requests. CSW stated that the decision to expand the initial review into a full study should be done on a case by case basis. Reliant commented that the type of study required would depend on the generator size and type, the generator's location on the grid, the size of customer load relative to the generator size, whether the service is radial or network, transformer connections, whether or not the customer plans to export to the utility's grid, whether the generator is pre-certified, and whether a line-extension is required. TNMP noted that distributed generation can be as simple as a solar cell or as complex as a gas turbine, and that it is difficult to specify the extent of the studies for these diverse resources. Although SPS stated that it is always necessary to conduct a study, the company also commented that a study may not be required if a generator were to connect to a site which has been designed to accommodate a certain level of generation if the addition of that generation falls below the maximum design level. SPS also commented that the utility should conduct a study to define the interconnection cost before proceeding.

DGC, Sonat, and Fowler Energy generally commented that it is not always necessary to conduct a pre-interconnection study, but clarified that if a study is conducted, it should reflect the benefits of interconnecting DG at a particular location. DGC commented that pre-interconnection studies would not be needed for any DG as set forth in §25.211 (g) (1) and additionally for non-exporting line-commutated inverter systems or inductive systems and non-exporting small synchronous or stand alone machines. DGC also commented that the only instance in which all three types of pre-interconnection studies might be required would involve the interconnection of a large exporting synchronous generator at a new customer site. EGS stated that it may be possible to eliminate some pre-interconnection studies for very small units after utilities have gained experience interconnecting distributed generators to the system. Fowler Energy stated that studies should only be conducted for generators larger than 500 kW because these generators may have an effect on the distribution system. TNMP commented that only distributed generators isolated from the utility system during normal operation with a verifiable open switch locked in the open position should be exempted from study.

EGS commented that if there are no more than two 50 kW units on the distribution grid, it may not be necessary to perform a coordination study. CSW stated that a coordination review, and possibly a study must be completed even if the facility is not exporting power into the distribution grid to ensure that the proper relaying and coordination exists to ensure a safe and reliable operation. However, CSW clarified that some instances may not require a full study, such as DG facilities of less than ten kW.

DGC commented that a customer that has been served in the past (prior to installation of DG) and does not wish to export power may not need a service study. However, if a customer wishes to export, a utility may require a service study to identify the physical facility changes that may be required to export power. DGC also noted that interconnection service to new customers with small non-exporting generators might require a service study, but also pointed out that service to a new customer that does not intend to install DG is just as likely to require a study. EGS explained that the deciding factor for a service study is not whether the DG unit exports its power; rather, it is whether the utility facilities are capable of handling the power flow in both directions for the attached generation capacity under worst case conditions.

CSW clarified that system impact studies are necessary only if the proposed generator will have a significant impact on a specific section of the utility's distribution system. DGC noted that larger synchronous systems may need this type of study; however, induction and line-commutated inverters do not contribute significantly to fault currents and also may not need a system impact study. Reliant commented that utility system impact studies are necessary for situations that may have a real impact on the utility's distribution system. TXU stated that a detailed system impact study is required whenever DG is operating in parallel with the distribution system.

Fowler Energy and SPS provided general comments regarding pre-interconnection studies. Fowler Energy commented that a pre-interconnection study should be limited to the effects that generators' output may have on the distribution system. If the utility evaluation encompasses too many aspects of the generation project it will increase the costs of the study and slow down the generation project. The size of the proposed DG project and the interconnection equipment requirements are the only items that should be of concern to the distribution company. SPS stated that if the unit plans to export power the host utility would look at equipment ratings, flow impacts, fault studies, and possibly stability studies. There may not be sufficient metering at the location or supervisory control and data acquisition (SCADA) may be required.

With respect to the entity that should perform these studies, CSW, Reliant, and SPS commented that the distribution utility should conduct the studies. These parties generally stated that a third party conducting these studies will increase costs and time needed to complete the studies. Only personnel working with the distribution systems and data on a continuous basis can practically keep abreast of ongoing and proposed changes to the utility distribution system. SPS also argued that the creation of a distribution independent system operator (ISO) would be required to make a third party analysis work, which would be unwieldy. TXU stated that third parties could conduct the studies, but it would be more efficient and less costly if the distribution utility performed the studies. EGS and TNMP generally agreed that third parties could and do conduct the studies requiring system modeling. These parties need data from the utility regarding the specific facilities because distribution facilities are all unique. The ISO or other consultants could perform the studies. TNMP also stated that, if the commission envisions one third-party entity performing the studies, it should consider using the Electric Reliability Council of Texas (ERCOT)-ISO as that single entity. The utility should have the right to appeal to the commission if it believes the studies done by a third party are flawed. DGC commented that the commission should require third parties to perform these studies because this type of service is widely available in the competitive market by marketers and manufacturers of DG technology. Third party providers of these studies would require certain information from the transmission and distribution company. This information could be provided in redacted form pursuant to the pending code of conduct rulemaking, to ensure that confidential and proprietary customer information is not released. CSW commented that requiring a third party to perform studies may provide a barrier to the development of DG in Texas.

DGC also pointed out that all utilities indicated that they have detailed operating information about their systems. This fact was the basis for utilities arguing that they should do the pre-interconnection studies. The array of answers regarding the nature of studies and costs of performing them illustrate the need for standardization. DGC opined that there is a "balkanization" of different databases and different practices among utilities in Texas that, in and of itself, poses a barrier to the implementation of DG in this state. DGC recommended that the commission consider steps to begin standardizing practices and making more widely available the operating information about different utility systems. This common knowledge can facilitate development of DG as well as other beneficial changes for Texas consumers.

The commission concludes that studies should be conducted by the distribution utility, because this type service is within the distribution planning function. Reliable, safe interconnection requires study by qualified persons or knowledge of the utility distribution system. However, independent third parties may conduct pre-interconnection studies in the event that the utility and DG customer agree to do so. In particular, if a utility typically relies on outside engineers to perform studies relating to the design and operation of the distribution system, a similar arrangement should be available for the DG customer. Additionally, the commission declines to change the provisions of §25.211 or §25.212 in order to specify the types of applications for which no study should be conducted. The rule as proposed did not specify applications for which no study is required. Due to both the lack of information and inconsistent nature of responses regarding the necessity and components included in pre-interconnection studies, the commission finds that it is not currently possible to accurately determine those instances, if any, when interconnection studies are not necessary. One reason for the inconsistency in responses may be the utilities' lack of actual experience with DG. As experience with DG in Texas develops, unnecessary study requirements should be eliminated. Unnecessary study requirements and their associated fees have the potential to increase transaction costs and to become institutional barriers for DG developers and retail customers in Texas. These barriers could deprive customers of the benefits of DG.

The commission emphasizes that it is committed to facilitating DG in Texas, not only because it is a customer entitlement under PURA, but also because it is a resource that provides system-wide benefits to the state's electric power industry. The commission recognizes the need for statewide standardization and simplification of practices among all distribution utilities that will have to interface with new market participants seeking to provide service to customers. The commission concludes that an interconnection manual for distributed generation similar to the ERCOT interconnection manual for large generators seeking interconnection to the transmission system should be developed under a separate proceeding. At a minimum, this manual should address: (1) those instances, if any, in which a pre-interconnection study may not be needed for a DG facility, (2) each type of pre-interconnection study and its associated cost, and (3) environmental considerations relating to increased use of DG in Texas.

Second, the commission sought comment on the appropriate level of fees, if any, a utility or other entity may charge a customer to offset its costs incurred to conduct a pre-interconnection study for distributed generation units. The commission requested comments on whether the distribution company should offer tariffed rates for studies and the appropriate pre-interconnection study fee, if any, for a distributed generation unit less than or equal to two megawatts (MW). The commission also sought comments on the appropriate fee for a pre-interconnection study for a DG unit that is greater than two MW. Parties were also asked to identify and explain any system benefits of DG that warrant the spreading of some or all of the costs of the studies among all distribution customers.

With respect to the factors that generally affect the cost of interconnection studies, TXU commented that the size of the DG unit and site-specific aspects are the major factors that govern how extensive the interconnection studies will be. TXU also maintained that whether a generator is planning to export power or not can have some impact on the cost of the studies, but generally will not be nearly as significant. Although DGC agreed that the size of generator affects the cost of the studies, the coalition also maintained that the type of the generator and whether the generator is exporting "significant" amounts of power onto the grid will also affect study costs. EGS stated that two factors affect the cost of the studies, the size of the unit and the number of

DG units already connected to the system or feeder. EGS added that, if variations of a study were requested by the DG developer to accommodate the interconnection, the cost would logically increase. CSW generally commented that smaller generating units will have fewer and less costly study requirements. CSW added that the coordination of protective devices can be simplified in some cases for DG facilities that will not be exporting energy into and across the utility system.

With respect to who should bear the cost of pre-interconnection study costs and fees, CSW, Reliant, TXU, TNMP, EGS, and SPS generally argued that the costs of the pre-interconnection studies should be borne by the DG customer. However, CSW proposed that no fee should be assessed to DG customers wishing to interconnect non-exporting units that are 10 kW or less in size. TXU proposed that no fee should be assessed to DG customers wishing to interconnect units up to 50 kW single phase and 150 kW three phase because the cost of the studies would be low enough that it would not warrant charging for the study. However, DGC, Sonat, and Fowler Energy generally stated that there are many instances where DG customers should not have to pay for study fees.

With respect to any system benefits of DG that would warrant the spreading of some or all of the study costs among all customers, DGC, Sonat, Fowler Energy, and Public Citizen generally maintained that there are both benefits of adding DG to the utility system and benefits of the information contained in the studies. These benefits would warrant spreading the cost of the studies among all customers of the distribution utility. These parties also contended that conducting pre-interconnection studies is an appropriate role of the regulated distribution planning function and costs, therefore, should be recovered from all customers through the utility's regulated distribution rates.

DGC generally commented that all customers in Texas will benefit from increased use of DG through peak shaving, demand side management, increased reliability, and deferral of transmission and distribution upgrades. Specifically, (1) Some DG will be installed in areas that are "strained" at certain times and with load growth will need to be upgraded or re-built. Interconnection of DG in these areas can offset or significantly delay the need for the facility upgrades. With averaged rates, this is a benefit to all customers. (2) DG interconnection in such a "strained" area or on "weak" feeders can help support the voltage in an area and can delay investment and improve the quality and reliability of the delivered power. Again, with averaged distribution rates this is a benefit to customers. DGC also maintained that the actual studies benefit other customers because the results of a study in many-cases can be used by other parties who desire to interconnect DG. DGC added that the benefits of the study are available to a wide range of potential customers of the utility and it would be wrong to treat a study as being dedicated to any particular customer. DGC also pointed out that a utility would normally include the costs for connecting new customers that do not plan to self-generate within the utility's distribution planning function. TXU stated that the fact that studies are conducted free of charge for consuming customers is irrelevant because the utility is dealing with different customer classes. Sonat commented that, although electric utilities should be reimbursed for all appropriate costs incurred to determine the impact of the interconnection of DG on their systems, the commission should carefully consider including those studies in the utility's planning function, warranting recovery of the costs recovered through the utility's cost of service mechanism. Sonat stated that, if the commission determines that impact studies are not a part of the utility's planning function, it would urge the commission to find that no incremental fees may be charged to customers by utilities for types of DG interconnections described in §25.211(g)(1). Public Citizen commented that DG facilities of 500 kW or less should not be assessed study costs. Sonat added that pre-certification may help offset or obviate the need for impact studies.

TXU, Reliant, CSW, EGS, and TNMP generally argued that the beneficiaries of DG are the DG customers, and the cost of interconnecting DG to the utility system outweighs any benefit that DG may add to the system. Therefore, the cost of such studies should be borne by the DG customer requesting interconnection rather than by all of the customers of a utility's distribution system. TXU specifically stated that the customer installing the DG is installing the units for its own benefit, either to serve its own load or to attempt to sell power in the open market. There is no readily quantifiable benefit to other customers on the distribution system or the distribution utility from the installation of DG, for the following reasons: (1) the distribution company is required to provide the necessary facilities for the distributed generator's back-up and maintenance power supply needs (or to meet the customer's full load requirements on a permanent basis should the customer decide to discontinue DG operations), (2) the fact that a distributed generator is installed on a feeder does not in any way enhance the reliability of the distribution system, since the generator is required for safety reasons to trip off line in the event of any system disturbance, and (3) to protect the integrity of the distribution system and ensure that other distribution customers are not adversely affected by the presence of the DG, the distribution utility must construct facilities to protect against service irregularities regardless of the manner of operation of the DG. TXU stated that, under very limited conditions, a system benefit of DG may occur at the transmission level. TXU clarified that this would be a situation where a distributed generator is interconnected with a feeder whose substation transformers are operating at rated capacity, the installation of a distributed generator that is of the correct size for the particular situation may allow for the temporary deferral of substation facilities by reducing the amount of load on the transformer. TXU added that deferral is only possible if there is some assurance that the distributed generation facility will be on line during peak periods. TXU requested that if the commission determines that the cost of studies should be spread among all customers, it should ensure that these costs are timely recovered by utilities through transmission and distribution rates to be set beginning next year under PURA §39.201. EGS commented that system wide subsidization would cause DG developers to request unneeded studies because they would be free of charge. EGS added that one can only assume that benefits will accrue to DG customers through on-site DG if one also assumes that the distribution company will have some control over the location of the interconnection and the operations of the DG units. EGS also maintained that DG developers will not site their units to best fit the delivery system but rather will connect and disconnect at the location most suitable for their uses. EGS clarified that, if the system needs the power for voltage regulation, neither the utilities nor the developers have any way to determine if their units will either help or hinder. Moreover, EGS noted that §25.211(e)(3) allows the utility to disconnect a DG unit from the grid in "cases where continuance of interconnection will endanger persons or property", and concluded that it would therefore be improper to require customers to subsidize an arrangement that may potentially harm customers, DG developers and their property. TNMP noted that DG has the benefit of potentially reducing loading on a heavily loaded circuit by providing supply at the load source and stated that DG could potentially expand supply sources for a competitive generation supply.

DGC responded to the comments of TXU and Reliant that DG would likely create operating difficulties, increase costs for distribution systems, and potentially hurt reliability. DGC asserted that these comments do not take into account new information systems and technology developments that will contain costs and improve reliability of DG systems. New technology-based systems under development include (1) automated systems that can perform lock-outs electronically, rather than manually, (2) systems for central dispatch of networks of DG based on power needs on individual circuits or in response to power pricing changes, and (3) the development of a "neuro-fuzzy" logic system that will monitor conditions on sub-sections of distribution systems in order to predict overloads and failures, and dispatch various remedies including calling up DG.

The commission reiterates that DG is a beneficial resource because it (1) provides electric system benefits during periods of capacity shortage, (2) enhances both the reliability of electric service and economic efficiency in the production and consumption of electricity, and (3) provides customers greater opportunities to control the price and quality of electricity within their facilities. However, the commission also realizes that the provision of DG is a competitive energy service that in many cases will be provided by retail electric providers (REPs). The question of who bears the costs incurred to interconnect a REP's new customers has not been resolved. Moreover, developers of large generation projects are required to bear the costs of interconnection studies. The commission finds that it is possible to strike an equitable balance that: (1) acknowledges the system-wide benefits of DG, and (2) recognizes that interconnections currently fall within the utility's distribution planning function and are likely to remain a apart of the distribution planning function.

The utility comments appear to concede that smaller non-exporting DG applications will not require extensive pre-interconnection studies. It also seems likely that these applications will be used to serve residential and small commercial customers. Requiring all customers to bear the costs of studies for these smaller applications will provide an incentive for DG development for residential and small commercial customers. The system-wide benefits that will accrue to all customers through the utilization of DG warrant having the utility bear the study costs for these small DG applications, recovering the costs in the rates of all customers of the distribution utility. The commission therefore revises the language set forth in §25.211 (g)(1) to preclude fees for pre-interconnection studies for pre-certified DG units up to 500 kW that export not more than 15% of the total load on a single radial feeder and also contribute not more than 25% of the maximum potential short circuit current on a single radial feeder. For other applications the costs of the studies are likely to be higher, and the benefits to an individual customer are likely to be significant. Accordingly, the DG customers should bear the costs of the studies, except in circumstances discussed above.

With respect to the appropriate fees for pre-interconnection studies, CSW, Reliant, DGC, Sonat, EGC, SPS, and Fowler Energy proposed specific cost caps or rate schedules for pre-interconnection study fees. Specifically, DGC stated that, if fees are charged, they should reflect a "contribution" toward distribution planning costs and should be capped according to the following fee schedule: (1) less than 10 kW, $100; (2) 10 kW to 500 kW, $300; (3) 500 kW to 2 MW, $500; and (4) 2 MW to 10 MW, $1,000. DGC additionally proposed that $100 should be added to the above cost caps for interconnection to a network system to compensate for additional reviews. TXU stated that DGC's proposed fees are too low to recover the costs that will be incurred to conduct such studies.

CSW proposed a fee schedule and stated that it should be made part of the electric utility tariff to be approved by the commission. CSW clarified that it would file this proposed fee schedule when modifying existing tariffs or offering new tariffs for interconnection and parallel operation of DG as required under §25.211(d). CSW added that the utility could propose changes to its fee schedule contained in its tariff to bring charges in line with its experience as it incorporates DG applications into its system. CSW's proposed fee schedule for non-exporting facilities seeking interconnection to a radial system is: (1) 0 to 10 kW, $0; (2) 11 kW to 400 kW, $200; (3) 401 kW to 2 MW, $400; and (4) 2 MW to 10 MW, $600. CSW's proposed schedule for exporting facilities seeking interconnection to a radial system is: (1) 0 to 10 kW, $100; (2) 11 kW to 400 kW, $400; (3) 401 kW to 2 MW, $1,000; and (4) 2 MW to 10 MW, $2,000. CSW's proposed schedule for non-exporting facilities seeking interconnection to a network system is: (1) 0 to 10 kW, $100; (2) 11 kW to 400 kW, $400; (3) 401 kW to 2 MW, $1,000; and (4) 2 MW to 10 MW,

$2,000. CSW also proposed that facilities seeking to interconnect to network systems with the intention of exporting power have their pre-interconnection study requirements and associated costs determined on a case-by-case basis.

CSW clarified that their proposed fee schedule takes into consideration: (1) determining the size of the interconnection equipment (typical costs range from $50-$100); (2) calculating the fault current contribution, if any, to the feeder system, determining the proper coordination of protective devices (typical costs range from $50-$700); (3) establishing metering requirements and designing metering equipment (typical costs range from $50-$200); and (4) compiling data on meters for load flow analysis, voltage drop calculations, etc., checking load levels on relevant equipment, and analyzing the power quality impact of the installation on other customers (typical costs range from $100-$1,000). CSW also noted that ERCOT requires each generator to pay fees for the utility's performance of pre-interconnection studies and imposes a deposit of $20,000 before a study will begin. The procedures also recognize that other studies may be required at cost to the generation customer. TXU stated that CSW's proposed fee schedule is too low and that most of the fees would be four to five times higher than CSW's.

Reliant also proposed a fee schedule and stated that the company was uncertain whether this schedule should be a stand-alone tariff, an item incorporated into this section, or an item incorporated into the tariff filings required under §25.211(d). TXU stated that Reliant's proposed fee schedule is generally acceptable with regard to the level of detail and amounts. Reliant's proposed fees are significantly higher than the fees proposed by CSW. The fees were also differentiated by a number of factors that it believes affect the costs of performing the studies.

EGS commented that the distribution utility should not offer tariffed rates for studies because the final costs can vary significantly on a case-by-case basis. EGS maintained that a $500 study fee may be appropriate for a unit less than or equal to two MW. However, EGS also stated that, because all feeders are different in configuration and response to loads, it is not possible to set an accurate fixed fee that would apply to certain levels of added distributed generation capacity. EGS added that the cost varies from $50 per hour for a simple coordination study to more than $500 per hour for a complete system impact study. A coordination study may cost up to $400 per hour. No fee structure could anticipate the variations in costs.

Fowler Energy commented that all studies should be capped at $100 per study because only a few items must be reviewed such as the distribution circuit in question for ampacity and short circuit current capability to determine whether the DG unit will have a detrimental effect on the system. Fowler Energy also opined that studies should be tariffed so that all customers will know the fees and scope of the studies; this will allow customers to better assess service dates and the economics of a DG project.

Sonat suggested that the interconnection tariff include specific fees and fee caps for interconnections that require studies. Sonat specifically proposed that an impact study should be capped at $250 for units less than or equal to 2 MW and $1,000 for units greater than 2 MW. For interconnection to network systems, Sonat proposed that there should be: 1) no charge for inverter systems under 20 kW, 2) 100 dollars for all other inverter systems, 3) 500 dollars for induction generators and synchronous generators up to two MW, and 4) 2,000 dollars for systems utilizing one or more synchronous generators, each generator being two MW or larger, irrespective of whether such systems include single or multiple generators. Sonat also commented that the commission should review any requirement for reimbursement of study costs annually.

SPS commented that fees for studies should be high enough so that questionable inquiries into the installation of DG would be discouraged and added that tariffed rates for studies should not be offered by the distribution utility. SPS submitted that the appropriate pre-interconnection study fee for a DG unit less than or equal to ten MW is $10,000.

TNMP stated that fees for studies should be competitively priced since these services are readily available in the market and also that the distribution company should offer tariffed rates for studies. TNMP suggested that an average cost could be developed if the commission determines that the utility should charge a flat fee. The company also recommended that the DG customer should pay a deposit prior to the commencement of the interconnection study to ensure that speculative requests are kept to a minimum.

TXU proposed that the cost of the studies be based upon an hourly rate, subject to periodic review, for the actual work done to perform the studies. TXU did not propose specific fees or cost caps for study fees, but rather stated that presently there is not enough history in working with DG being installed on a radial distribution system to accurately quantify the "normal" or "average" cost that a utility would likely incur for the completion of such studies. TXU, Reliant, and CSW also commented that additional transmission studies may be necessary and such studies and costs would be additional.

The commission applauds both Reliant and CSW for submitting initial cost estimates for pre-interconnection study fees. Study fees fixed in tariffs are needed to permit DG customers to more accurately assess the economics of the DG project. However, due to the lack of supporting cost data for such studies, the commission does not find it appropriate to prescribe fees or fee caps in the rule. The commission concludes that CSW's approach is reasonable. Each utility would file its pre-interconnection study costs for approval (with supporting cost data) at the same time it modifies existing tariffs or submits new tariffs to provide standby service for DG customers. The commission revises the language in the standardized Tariff for Interconnection and Parallel Operation of Distributed Generation form to reflect this process.

Third, the commission sought comment on the necessity of including a universal indemnification requirement in this section and requested that parties provide universal indemnification language.

EGS, TNMP, Reliant, TXU, and CSW supported a universal indemnification requirement. EGS stated that two types of indemnification are necessary. The first is indemnification in the form of insurance protecting the DG developer and the second is indemnification in the form of tariff language that places responsibility for accidents and damage caused by the DG facilities on the DG developer, and not on the utility. EGS also proposed that the indemnification requirement be segregated based on system size. Reliant, EGS, and TNMP offered specific indemnification language that they believed should be added to §25.211.

TXU stated that it would support a rule that includes indemnification provisions and further proposes that a limitation of liability provision also be included in the rule, in order to protect the utility and the general body of distribution ratepayers from any possible liability that might arise due to the interconnection of the distributed generator onto the system. TXU proposed that each utility be able to include provisions in its interconnection tariff or agreements that are identical to their present tariff provisions or a similar limitation provision of any other utility that has been approved by the commission. Alternatively, the rule could include a single uniform statewide provision based on the one relied on by Reliant Energy in *Houston Lighting & Power Co. v. Auchan USA, Inc.*, 995 S.W.2d 668 (Tex. 1999).

The CSW Companies proposed the inclusion of a provision in the proposed Distributed Generation Interconnection Agreement that would require the owner of the DG resource to obtain minimum insurance coverage, or otherwise demonstrate that it has adequate financial resources to respond to claims that arise from the operation of its facilities, with regard to interconnection and parallel operation of its facilities.

Sonat and DGC opposed a universal indemnification requirement because it would represent a barrier to DG facility development. Sonat argued that a universal indemnification is an absolute barrier to the development of DG and true competition. Sonat maintained that the better alternative is an appropriate allocation of risk among all of the parties involved, and that indemnification should be allowed only when there is proof that the customer violated the technical requirements of the rules that resulted in damage to the utility's system. Sonat further suggested that there should be an absolute limit or cap on indemnification. The cap should be commensurate with the economic investment of the customer and the size and type of DG, and units of less than 500 kW should never require any indemnification. DGC maintained that indemnification would be a barrier to DG technology; however, if the commission were to adopt a policy of universal indemnification, it offered the following suggestions. First, the tariff should provide for mutual indemnification because the customer should not be asked to give this protection without being granted the same protection in return. Second, under no circumstances should any generator with a rated capacity of less than 500 kW require any indemnification. Finally, the commission could require liability insurance to insure against accidents, and the level of insurance required should vary with the size of the generator. TXU stated that the size of the generator should not exempt it from indemnification requirements. TXU agreed, however, with the concept that DG operators should be able to purchase insurance in order to meet whatever indemnification requirements they might have.

The commission concludes that mutual indemnification and limitations of liability between the company and customer are appropriate in order to protect the utility, its ratepayers, and the DG customer from any possible liability that might arise due to the interconnection of DG onto the distribution system. Mutual indemnification is the most reasonable approach because it requires each party to bear the consequences of its negligence.

The commission is pleased that several parties in this proceeding were able to effectively negotiate reasonable indemnification and limitation of liability provisions for incorporation into the standard Agreement for Interconnection and Parallel Operation of Distributed Generation. The provisions are modeled after the indemnity provisions in the commission's open access transmission rule and the Federal Energy Regulatory Commission's (FERC) pro-forma open-access tariff. The negotiated indemnification provision is subject to any limitation of liability provisions that currently exist in utility tariffs as to the relationship between the utility and the DG owner for delivery of electricity over the utility's distribution system to the DG owner. The commission concludes that a standard agreement addressing universal indemnification will further streamline the interconnection of DG, because it will eliminate the necessity of negotiating these provisions on a case-by-case basis.

The commission does not find it necessary to include an additional insurance provision in the agreement that would require DG customers to provide the utility with a certificate of insurance in an amount that is reasonably satisfactory to the company as proposed by CSW. The commission is willing to consider an appropriate insurance requirement with specific liability limits, in connection with the review of the compliance tariffs required in this proceeding, but insurance that is subject to the utility's sole discretion could easily be used as an unreasonable barrier to DG installation. The commission is adopting a standard agreement for interconnection and parallel operation of distributed generation that includes the indemnification provision agreed to by a number of the parties that participated in this proceeding.

Fourth, the commission sought comment on any instances where there should be exceptions to the interconnection guidelines set forth in §25.211(h).

CSW expressed that there should be exceptions to the guidelines set forth in §25.211(h). For cases in which there is some doubt regarding the utility's ability to successfully interconnect a distributed generator in parallel with a secondary network system, CSW recommended that these installations be evaluated on a case-by-case basis. CSW also proposed a clarification of §25.211(h)(1)-(3) in describing certain DG applications. DGC supported CSW's proposed change.

EGS stated two broad considerations of adding distributed generation to secondary network systems. For a "closed loop" network, EGS argued that adding a distributed generation unit is possible, but extra time is required for determining all the interdependencies and unintended consequences of adding a unit to the network, which makes studies more costly. For the "secondary mesh" network, DG should not be added to the network unless the service can be reconfigured to be an isolated radial feeder. According to EGS, the technology of network protective devices is not capable of managing distributed generation units connected to the secondary mesh network.

Reliant recommended that DG facilities not be approved for spot or street network systems and proposed that a network customer requesting to install distributed generation should change its type of service to a radial feed. If the customer wishes to continue network service, or if radial circuits are not available, then, at the customer's expense, it is possible to rebuild the network system utilizing breakers and protective relaying that is similar to that used for the transmission service where the generation is commonly connected in a network arrangement. Reliant stated that IEEE PC37.108-1989 (R1994), *Guide for the Protection of Network Transformers*, advises that network protectors should not be used as a separation device between a network system and a distributed source of generation, because network protectors were not designed to withstand the recovery voltages present during switching operations and fault clearing. DGC disagreed with Reliant's comments that "just say no" to DG connecting to the spot or street network. DGC noted that Reliant gives an example of problems on some networks that had DG. DGC clarified that this example is the same type of example given by Reliant during the workshops about problems on networks that did not have DG on them. They are design, operation, and/or setup problems with the network that are irrespective of whether DG is on the network. DGC maintained that the DG should not be penalized, out of hand, for design, operation, and/or setup problems of networks and that DG interconnected to networks deserve more careful review but not dismissal.

SPS recommended that there be no exceptions to the interconnection guidelines set forth in §25.211(h). SPS commented that even portable generators should be subject to some type of regulation, because a lineman can be killed if he thinks the system is dead but is actually hot because of back flows into the system caused by a customer-owned generator.

TXU related experience where DG was installed on a network on its distribution system. In the experience cited, there was only one customer on the network bus, and in all cases, the generator size was less than the minimum load on the network, i.e., there was no exporting of power out of the network. TXU stated that if an individual customer served from a network wished to install DG with the intention of exporting power, the utility should be allowed to disconnect that customer from the network service and provide service from a radial system, with the customer bearing the cost of such change in service. TXU added that in cases where a network had more than four sources, the 25% limit would exceed the capacity of any one feeder and would exceed the capacity of the network transformer. TXU proposed modifications to §25.211(h)(1) and (h)(2) to address this fact.

The commission finds that CSW's proposed change to §25.211(h)(1)-(3) is appropriate because it more accurately reflects the intent of the rule and appropriate conditions for safe interconnection. The commission does not find it necessary to make any other changes to this proposed subsection because this subsection properly acknowledges that aspects of secondary network systems create technical difficulties. This subsection allows a utility to reject applications for interconnection if it can demonstrate specific reliability or safety reasons why the generator should not be interconnected at the requested site. The commission concludes that this language appropriately accommodates both network customers desiring access to DG and utilities with specific reliability or safety concerns regarding the provision of interconnection to a network system. However, the commission does not find appropriate the suggestion that DG facilities for spot or street network systems simply not be approved for interconnection, because this requirement would unnecessarily discriminate against DG installations requesting this type of service. Interconnection requests to network systems warrant a more detailed analysis and review by the utility, but not uniform dismissal.

Fifth, the commission asked whether interconnection disputes be handled in an expedited manner and requested parties to provide examples of expedited processes that have been utilized for handling complaints.

Reliant, TXU, and CSW generally stated that the open access transmission alternative dispute resolution (ADR) process is an appropriate model for handling interconnection disputes. Reliant also provided a modified ADR rule made applicable to DG disputes. TXU suggested that use of the ERCOT ADR procedures would provide for consistency among all sizes of generators.
CSW concurred that the open access transmission dispute resolution procedures should be adopted.

Several parties offered alternatives to the ERCOT ADR process. TNMP argued that the only reason why a distribution company would refuse to interconnect a distributed generator would be an instance where the utility thought that an interconnection would endanger personnel or negatively effect the service to other customers. TNMP suggested that an independent third party should perform a study in the event of a safety concern and added that the dispute resolution process should be similar to ADR, but more analytical. SPS stated that a panel set up for the express purpose of dealing with disputes should expeditiously handle complaints. EGS commented that, in the "simplest" cases, an expedited complaint handling and arbitration procedure could be allowed. EGS also suggested that complaint resolution could be modeled after §§22.321-22.327 of this title (relating to post-interconnection agreement dispute resolution). EGS recommended against an expedited process because of safety concerns. EGS commented that an ADR process could work, but only if the arbitrator considers detailed evidence by the utility justifying the refusal. EGS added that the utility should be absolved of liability in the event that the commission orders an interconnection to which the utility objects. DGC maintained that the customer and the utility should always make an initial good faith effort to resolve differences before resorting to more formal dispute resolution. However, in the event that disputes are not resolvable, DGC proposed that the dispute resolution process be modeled after the provisions set forth in §25.30 of this title (relating to complaints). DGC explained that, under this process, the customer would first complain to the utility and the utility would have two business days to investigate and advise the complainant of the results in writing. If the complainant is dissatisfied with the results of the electric utility's complaint investigation, the electric utility would have to advise the complainant of the commission's informal complaint resolution process. DGC also submitted that all complaints referred to the commission's Office of Customer Protection (OCP) should be resolved within two business days. If the complainant is dissatisfied with the resolution, then the informal dispute resolution would begin with OCP serving as mediator. TXU did not support the dispute resolution model proposed by DGC. TXU stated that due process requirements are going to mandate notice and an opportunity for hearing, and added that one "can go the dispute resolution route" but questioned the legality of the commission's ability to enter an order ex parte of that nature. TXU also questioned OCP's ability to hand down judicial type decisions.

The commission concludes that the complaint procedures set forth in the Commission's Procedural Rules §22.242 (relating to Complaints) provides the best framework for addressing interconnection disputes. These procedures allow parties to engage in informal dispute resolution within a 35 day time period and to pursue formal complaints in the event that the informal resolution process has failed. However, the complex technical issues inherent in interconnection disputes will require analysis by staff possessing expertise in matters relating to DG. Therefore, the commission requires that all informal complaints be presented to the Office of Regulatory Affairs rather than the Office of Customer Protection.

Sixth, the commission asked whether the term "inverter-based protective functions" as stated in §25.211 (h)(1) of this title should be defined and tied to a specific industry operating standard.

CSW proposed that the term "inverter-based protective functions" be defined in §25.211 as follows: *Inverter-based protective functions – Functionality implemented in an inverter system, using hardware and software, designed to prevent unsafe operating conditions from occurring before, during, and after interconnection of inverter-based static power converter units with the utility system. These functions shall meet or exceed recommended practices for 'power quality'* *and 'safety and protective functions' as found in IEEE P929, Draft 11, July 1999. For purposes of this definition, unsafe operating conditions are conditions that, if left uncorrected, would result in harm to personnel, damage to equipment, unacceptable system instability or operation outside legally established parameters affecting the quality of service to other customers connected to the utility system*. DGC supported CSW's proposed language except for the second sentence. DGC clarified that the referenced IEEE document is not yet released for public comments and is in an internal drafting process. Therefore, it would be too early to apply that requirement to this definition. DGC explained that the remaining parts of the proposed definition explain and clarify the intent of "inverter-based protection functions".

EGS stated that the term "inverter-based protective functions" may be defined as *those software functions formerly required to reside in specific utility grade equipment for the purpose of controlling the power flow conditions at the point of common coupling under both normal and abnormal conditions*. EGS pointed out that an IEEE working group P1547 is preparing a standard to use for defining and testing of those functions in electronic devices residing in the inverter, but that until the IEEE standard is completed, no standard exists to verify the claims of any specific manufacturer's equipment. EGS stated that until such a standard is created, the risk of allowing the use of the inverter-based protective functions to replace utility grade protective equipment should be should be judged by the utility to whom a request has been made for connection of such equipment on a case-by-case basis.

Reliant stated that "inverter based protective functions" is not commonly used in the industry to describe a type of protective system used in distributed generation. Reliant recommended that such systems not be approved for use until they can be tested and evaluated. Reliant also pointed out that while inverter systems exist today, advanced systems that control and coordinate generator output power do not yet exist, nor have any standards for their design been proposed or adopted. Reliant further commented that, as DG evolves and inverter based control systems designs and standards proliferate, their operation on network systems can be evaluated and tested.

TXU proposed that the term "inverter based protective functions" not be defined. TXU's understanding was that these types of devices are not in widespread production or use and that there are no uniform standards for their design, and an accurate definition would be very difficult to develop at this time.

The commission concludes that including a definition for inverter-based protective function is necessary because it will reduce any confusion with respect to network interconnection of distributed generation as set forth in §25.211(h)(1). The commission accepts CSW's proposed language and agrees with DGC that the sentence referring to an IEEE document should not be included in the definition because it is currently in draft form. The commission may find it necessary to revisit this issue and modify this definition after the IEEE standard is finalized.

Comments on 25.211(a)

EPE suggested that an additional sentence should be added to the applicability subsection of the rule, which states that this section shall not apply to an electric utility not subject to PURA §39.102(c). DGC however, commented that EPE is subject to the provisions set forth in these sections because PURA §39.101(b)(3) grants a customer the right of access to "on-site distributed generation." DGC argued that EPE may therefore be exempt from Chapter 39, but its customers are not. DGC also noted that PURA Chapter 39 delegates the commission the authority to adopt and enforce rules to enforce the customer protections granted in that chapter.

The commission concludes that EPE is not subject to the provisions set forth in these sections until the expiration of the utility's rate freeze period and changes §25.211(a) to reflect this conclusion.

Comments on 25.211(c)

With respect to §25.211(c) (relating to definitions), several parties proposed changes. Sonat pointed out that this section lacks a definition for "qualifying facility" which could be used to clarify the relationship between electric power end-users, utilities and non-utility generators.

The commission notes that the term "qualifying facility" is defined in §25.5 of this title (relating to Definitions) and therefore does not deem it necessary to included the definition in these sections.

CSW proposed that the term "exporting" be defined in the rules to mean "Any distributed generation facility that has the potential or capability of placing energy on the utility's distribution system."

DGC disagreed with CSW's proposal and stated that "exporting" as discussed in the workshops is "Any distributed generation facility that places energy on the utility's distribution system beyond the point of interconnection for the purpose of having the power move from the facility to a buyer (or customer) for the power." DGC also commented that the need for "reverse power sensing", which would not be a trip function but rather a feedback to the generator to reduce output to get below zero power (importing) at the point of interconnection also was discussed in the workshops; the specific level that the generator could "swing" onto the grid was not defined. DGC pointed out that, in preparing for similar proceedings in California, for non-exporting generators PG&E has proposed a limit of power that could be put onto the grid during a transient based on the capacity of the interface beyond which the generator must trip (*e.g.,*. 10% of the interface capacity). This proposal might be a reasonable way to limit the amount of temporary power put onto the grid. DGC clarified that this does not apply to an exporting generator or to a net-metering arrangement.

The commission declines to accept CSW's proposed definition for the word "exporting". The commission concludes that the concept of "exporting" is self-explanatory; it consists of a DG facility placing energy on the utility's distribution system beyond the point of interconnection.

TXU and CSW argued that the proposed definition for "facility" is not consistent with the physical limitation that was agreed upon in the workshops, during the development of this proposed rule. TXU and CSW Companies urged that the definition be changed back to its form contained in staff's proposal for publication. Sonat commented that there appears to be a disconnect between the definition of "facility" in proposed §25.211 (c)(5) and the definition of "on-site distributed generation" in proposed §25.211(c)(8), as well as definitions in the proposed form of interconnection agreement. Sonat recommended that this be clarified so that a customer will know the size and number of distributed generation units for which it may request interconnection.

The commission accepts this proposed change and agrees that the definition of "facility" that was agreed upon in the workshops furthers the intent of the rule which is to create standardized procedures for safe and reliable interconnection of DG to utility distribution systems. DG facilities greater than ten MW will in many instances be required to interconnect at transmission voltage and would not be subject to the provisions set forth in these sections. In addition, ten MW is generally within the range of loads that will be served by a single feeder.

Comments on 25.211(d)

Regarding §25.211(d) (relating to obligation to serve), TXU argued that this section requires a utility to modify existing tariffs or propose a new tariff for interconnection that ensures that certain services are available to all customer classes that desire such service. TXU stated that it should not be required to significantly modify existing tariffs simply to meet the style of the proposed form when more minor modifications will produce the same result. TXU suggested that the language contained in this subsection be changed to reflect this fact.

The commission declines to revise the language set forth in §25.211(d), requiring each utility to modify existing tariffs or offer new tariffs for interconnection and parallel operation of distributed generation customers. The purpose of this requirement is to ensure that all customers in Texas have access to distributed generation as set forth in PURA §39.101(b)(3). This provision should make the DG tariff provisions more accessible to prospective DG customers.

As noted in a report submitted by the DG task force addressing tariff and policy issues a review of utility tariffs revealed that a majority of the utilities have one or more commission-approved tariffs to provide electric service to qualifying facilities (QF) or non-QF customers. However, it was also reported that some utilities offer multiple tariffs that may apply to all DG customers, while others may offer tariffs applicable only to QFs. For example, all utilities in Texas have tariffs to provide standby service to QFs, while not all utilities have tariffs to provide standby service to non-QF customers. Additionally, the parties noted that a number of existing standby tariffs did not apply to all rate classes. The commission concludes that these inconsistencies necessitate that each utility have an interconnection tariff that clearly lists the charges for standby service (maintenance, supplemental, and backup), charges for interconnection studies, and a standard application and agreement for interconnection and parallel operation of DG. The standard tariff form will accomplish this requirement and ensure that all rate classes and non-QF customers with DG facilities have access to standby service. The commission envisions that each utility will simply use the standard tariff form when extending the applicability of or offering new standby rates to all customer classes. Furthermore, the commission concludes that all DG tariffs, the standard interconnection application, and interconnection agreement shall be located together in each utility's tariff manual. This will help streamline the interconnection process for DG developers, increase efficiency, and help to facilitate the interconnection of DG in Texas.

Comments on 25.211(e)

CSW recommended that §25.211(e) (relating to disconnection and reconnection) be revised to reflect that reconnections will be subject to the customers' successful completion of any electrical inspections required by local electrical codes.

TXU and CSW proposed an additional paragraph which explicitly allows a utility to disconnect a distributed generator that does not comply with the applicable requirements that may be imposed elsewhere in the commission's rules. DGC disagreed with this proposal and stated that, if such a report is desired and required, the generator should have some notice of non-compliance and an opportunity to come into compliance before the facility would be disconnected.

The commission concludes that it is not appropriate to allow utilities to disconnect a distributed generator because it does not comply with the applicable requirements that may be imposed elsewhere in the commission's rules. The commission concludes that non-compliance with requirements set forth in other commission rules will subject that generator to the provisions regarding non-compliance contained within that rule.

Comments on §25.212

DGC also commented on a statement made by Reliant that claimed that Reliant Energy will require that all distributed generators be located on their own service transformer separate from other distribution customers even though the requirement is not specifically addressed in the proposed sections. DGC argued that Reliant can not be allowed to *require* protective equipment that the rule does not expressly require. One of the purposes of the rule is to create standard terms and conditions for interconnection of DG, and utilities should not be allowed to deviate from these standards by requiring extraneous specifications outside the scope of the technical requirements in the rule. Reliant also provided comments and concerns regarding the technical standards set forth in §25.212. For example, Reliant requested that the utility be afforded immediate 24-hour 365-day access to the disconnecting device required in subsection (c)(8) of this section. Reliant also commented that the rapid proliferation of distributed generators will increase the duration of outages and system reliability because there will be the need to locate, isolate and tag all sources of electric energy, including distributed generators, to indicate that employees are at work on a de-energized circuit. Reliant also recommended additional training for utility linemen and distribution system engineers, as distributed generators proliferate, so that such personnel may learn how to identify and locate any offending distributed generator, especially where there are multiple generators on one circuit. In addition, Reliant expressed concern that if the number of distributed generators on a circuit is significant, and they are being relied upon for voltage support, then normal voltage may not be restored when the utility energizes a circuit that has tripped due to a fault. Reliant noted that in the event of a fault on the circuit they are connected to, generators must separate from the utility's circuit within ten cycles and wait until normal voltage and frequency are present before reconnection to the utility's circuit. Reliant also recommended that the customer be required to perform annual testing of the distributed generator and the associated systems, including protective functions and the disconnecting means.

Sonat recommended that the number of cycles within which the customer should automatically disconnect should be 30 cycles rather than 10 cycles as required in §25.212(c)(1). Sonat asserted that the suggested change would reduce the cost of distributed generation without compromising customer benefits or grid safety.

The commission reiterates that the purpose of §25.212 is to describe the procedures for safe and effective interconnection of distributed generation. It is the intent of this rule that DG facilities that meet or exceed the technical standards set forth in §25.212 shall be allowed to interconnect to a utility's distribution system. The provisions set forth in these sections are not to be interpreted as minimum technical standards or requirements to which a distribution utility may add additional items at its own discretion. Reliant's statement that it will require that all distributed generators be located on their own service transformer separate from other distribution customers is inconsistent with §25.212, as it is being adopted. This rulemaking afforded Reliant the opportunity, both during the workshops and the formal comment period, to raise and provide justification for additional standards that it believes are appropriate. It has not made a case that a "separate transformer" rule is necessary for safe and reliable interconnection of DG; nor has Sonat made a case that the number of cycles within which the customer should automatically disconnect should be 30 cycles rather than 10.

Comments on proposed forms

Regarding the proposed forms, TXU argued that utilities should not be constrained to the exact format of the proposed tariff form for three reasons. First, the form is too prescriptive with respect to modifying existing tariffs. Second, the utility should be allowed to insert appropriate language in the application section of the rate schedule to maintain consistency with its existing tariffs. Finally, the utility should be allowed to place the application for Interconnection with in the Service Regulation section of its tariff manual, separate from the Rate Schedules, to maintain consistency with the organization of the utility's Tariff for Electric Service. Reliant asserted that the term "facility" contained in the Interconnection Agreement is inconsistent with §25.211 and

§25.212. Reliant suggested modifications to the Interconnection Agreement to clarify that it must yield to the commission's rules if an inconsistency arises. Several parties made non-substantive changes that were incorporated into the proposed forms.

The commission concludes that the purpose of these standard forms is to simplify and streamline the process of DG interconnections. The commission does not find the format of the forms too prescriptive and declines to make any substantive changes to them. With respect to the inconsistent use of the term "facility", the commission finds that there is no need to change the treatment of the term "facility" in the Interconnection Agreement now that the commission has changed the definition of the term "facility" in §25.211(c).

General comments

DGC supported the commission's idea of a "Distributed Generation Interconnection Manual" that would provide more detailed rules on interconnection, pre-interconnection studies and pre-interconnection study costs.

With respect to pre-certification of DG equipment, Sonat agreed that pre-certification should be done by a third party and recommended that the entities be chosen by a committee equally staffed by utilities and DG manufacturers and distributors (e.g. underwriters laboratory or international testing service). DGC additionally commented that the goal of pre-certification is to simplify the process of interconnecting DG and added that utilities should not further complicate the process by providing redundant services. A pre-certified unit will have a third party verification that it complies with the technical portions of these rules and there is no reason for a utility to verify that which is certified by the third party pre-certification entity. If utilities redundantly perform these functions, there will be no benefit to pre-certification.

The commission emphasizes that there is a need to standardize statewide practices to adequately facilitate DG as required under PURA. The commission reiterates that pre-certification is important and should be conducted by an independent third party. Units that are pre-certified shall not be subject to further review of their design by the utility. A separate commission proceeding will be initiated to develop an interconnection manual for DG and identify entities to perform pre-certification.

Public Citizen also commented that the commission could de-average distribution prices and require the utilities to charge near zero for areas with excess distribution capacity and assess high charges in areas with congested distribution facilities. Similarly, Performance Based Ratemaking mechanisms could be designed with incentives for distributed resources. Making customers pay the full incremental cost of distribution will provide an incentive to make more rational decisions about the deployment of distributed resources.

Public Citizen also recommended that the commission, by rule, require the ISO to certify areas that are in need of capacity or that have transmission constraints and require the distribution utility to offer higher buy-back rates in those areas that reflect the cost of transmission upgrades.

The commission agrees that proper siting of DG may ease transmission and distribution congestion and concludes that the ratemaking proposals submitted by Public Citizen warrant further investigation. However, these matters are beyond the scope of this proceeding.

Public Citizen also recommended that the commission adopt a rule that requires any unit that is dispatched as a generating unit to meet power needs for more than 20 hours a year be deemed a new source of supply and be required to apply for an air permit at the Texas Natural Resources Conservation Commission (TNRCC) in order to encourage the deployment of environmentally beneficial distributed resources. Public Citizen urged the commission to ask TNRCC to add these units to its permitting requirements.

The commission concludes that air-permitting requirements are not under the jurisdiction of the commission and are therefore beyond the scope of this proceeding. The commission urges Public Citizen to participate in the future commission proceeding relating to the interconnection manual and to continue its dialogue with TNRCC staff.

All comments, included any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

These new sections are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction, and PURA §39.101(b)(3) which requires the commission to ensure that customers have access to providers of energy efficiency services, to on-site distributed generation and to providers of energy generated by renewable energy resources.

Cross Reference to Statutes: Public Utility Regulatory Act: §§14.001, 14.002, 31.002, 39.101(a), 39.101(b)(3).

§25.211. Interconnection of On-Site Distributed Generation (DG).

(a) **Application.** Unless the context clearly indicates otherwise, in this section and § 25.212 the term "electric utility" applies to all electric utilities as defined in the Public Utility Regulatory Act (PURA) §31.002 that own and operate a distribution system in Texas. This section shall not apply to an electric utility subject to PURA § 39.102(c) until the expiration of the utility's rate freeze period.

(b) **Purpose.** The purpose of this section is to clearly state the terms and conditions that govern the interconnection and parallel operation of on-site distributed generation in order to implement PURA §39.101(b)(3), which entitles all Texas electric customers to access to on-site distributed generation, to provide cost savings and reliability benefits to customers, to establish technical requirements that will promote the safe and reliable parallel operation of on-site distributed generation resources, to enhance both the reliability of electric service and economic efficiency in the production and consumption of electricity, and to promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints. Sales of power by a distributed generator in the wholesale market are subject to the provisions of this title relating to open-access comparable transmission service for electric utilities in the Electric Reliability Council of Texas (ERCOT).

(c) **Definitions.** The following words and terms when used in this section and §25.212 of this title (relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation) shall have the following meanings, unless the context clearly indicates otherwise:

(1) **Application for interconnection and parallel operation with the utility system or application —** The standard form of application approved by the commission.

(2) **Company —** An electric utility operating a distribution system.

(3) **Customer —** Any entity interconnected to the company's utility system for the purpose of receiving or exporting electric power from or to the company's utility system.

(4) **Facility —** An electrical generating installation consisting of one or more on-site distributed generation units. The total capacity of a facility's individual on-site distributed generation units may exceed ten megawatts (MW); however, no more than ten MW of a facility's capacity will be interconnected at any point in time at the point of common coupling under this section.

(5) **Interconnection —** The physical connection of distributed generation to the utility system in accordance with the requirements of this section so that parallel operation can occur.

(6) **Interconnection agreement —** The standard form of agreement, which has been approved by the commission. The interconnection agreement sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system.

(7) **Inverter-based protective function —** A function of an inverter system, carried out using hardware and software, that is designed to prevent unsafe operating conditions from occurring before, during, and after the interconnection of an inverter-based static power converter unit with a utility system. For purposes of this definition, unsafe operating conditions are conditions that, if left uncorrected, would result in harm to personnel, damage to equipment, unacceptable system instability or operation outside legally established parameters affecting the quality of service to other customers connected to the utility system.

(8) **Network service —** Network service consists of two or more utility primary distribution feeder sources electrically tied together on the secondary (or low voltage) side to form one power source for one or more customers. The service is designed to maintain service to the customers even after the loss of one of these primary distribution feeder sources.

(9) **On-site distributed generation (or distributed generation) —** An electrical generating facility located at a customer's point of delivery (point of common coupling) of ten megawatts (MW) or less and connected at a voltage less than or equal to 60 kilovolts (kV) which may be connected in parallel operation to the utility system.

(10) **Parallel operation —** The operation of on-site distributed generation by a customer while the customer is connected to the company's utility system.

(11) **Point of common coupling —** The point where the electrical conductors of the company utility system are connected to the customer's conductors and where any

transfer of electric power between the customer and the utility system takes place, such as switchgear near the meter.

(12) **Pre-certified equipment —** A specific generating and protective equipment system or systems that have been certified as meeting the applicable parts of this section relating to safety and reliability by an entity approved by the commission.

(13) **Pre-interconnection study —** A study or studies that may be undertaken by a company in response to its receipt of a completed application for interconnection and parallel operation with the utility system. Pre-interconnection studies may include, but are not limited to, service studies, coordination studies and utility system impact studies.

(14) **Stabilized —** A company utility system is considered stabilized when, following a disturbance, the system returns to the normal range of voltage and frequency for a duration of two minutes or a shorter time as mutually agreed to by the company and customer.

(15) **Tariff for interconnection and parallel operation of distributed generation —** The commission-approved tariff for interconnection and parallel operation of distributed generation including the application for interconnection and parallel operation of DG and pre-interconnection study fee schedule.

(16) **Unit —** A power generator.

(17) **Utility system —** A company's distribution system below 60 kV to which the generation equipment is interconnected.

(d) **Obligation to serve.** No later than 60 days after the effective date of this section each electric utility shall file a tariff or tariffs for interconnection and parallel operation of distributed generation in conformance with the provisions of this section. The utility may file a new tariff or a modification of an existing tariff. Such tariffs shall ensure that back-up, supplemental, and maintenance power is available to all customers and customer classes that desire such service until January 1, 2002. Any modifications of existing tariffs or offerings of new tariffs relating to this subsection shall be consistent with the commission approved form. Concurrent with the tariff filing in this section, each utility shall submit:

(1) a schedule detailing the charges of interconnection studies and all supporting cost data for the charges;

(2) a standard application for interconnection and parallel operation of distributed generation; and

(3) the interconnection agreement approved by the commission.

(e) **Disconnection and reconnection.** A utility may disconnect a distributed generation unit from the utility system under the following conditions:

(1) **Expiration or termination of interconnection agreement.** The interconnection agreement specifies the effective term and termination rights of company and customer. Upon expiration or termination of the interconnection agreement with a customer, in accordance with the terms of the agreement, the utility may disconnect customer's facilities.

(2) **Non-compliance with the technical requirements specified in §25.212 of this title.** A utility may disconnect a distributed generation facility if the facility is not in compliance with the technical requirements specified in §25.212 of this title. Within two business days from the time the customer notifies the utility that the facility has been restored to compliance with the technical requirements of §25.212 of this title, the utility shall have an inspector verify such compliance. Upon such verification, the customer in coordination with the utility may reconnect the facility.

(3) **System emergency.** A utility may temporarily disconnect a customer's facility without prior written notice in cases where continued interconnection will endanger persons or property. During the forced outage of a utility system, the utility shall have the right to temporarily disconnect a customer's facility to make immediate repairs on the utility's system. When possible, the utility shall provide the customer with reasonable notice and reconnect the customer as quickly as reasonably practical.

(4) **Routine maintenance, repairs, and modifications.** A utility may disconnect a customer or a customer's facility with seven business days prior written notice of a service interruption for routine maintenance, repairs, and utility system modifications. The utility shall reconnect the customer as quickly as reasonably possible following any such service interruption.

(5) **Lack of approved application and interconnection agreement.** In order to interconnect distributed generation to a utility system, a customer must first

submit to the utility an application for interconnection and parallel operation with the utility system and execute an interconnection agreement on the forms prescribed by the commission. The utility may refuse to connect or may disconnect the customer's facility if such application has not been received and approved.

(f) **Incremental demand charges**. During the term of an interconnection agreement a utility may require that a customer disconnect its distributed generation unit and/or take it off-line as a result of utility system conditions described in subsection (e)(3) and (4) of this section. Incremental demand charges arising from disconnecting the distributed generator as directed by company during such periods shall not be assessed by company to the customer. After January 1, 2002, the distribution utility shall not be responsible for the provision of generation services or their related charges.

(g) **Pre-interconnection studies for non-network interconnection of distributed generation.** A utility may conduct a service study, coordination study or utility system impact study prior to interconnection of a distributed generation facility. In instances where such studies are deemed necessary, the scope of such studies shall be based on the characteristics of the particular distributed generation facility to be interconnected and the utility's system at the specific proposed location. By agreement between the utility and its customer, studies related to interconnection of DG on the customer's premise may be conducted by a qualified third party.

(1) **Distributed generation facilities for which no pre-interconnection study fees may be charged.** A utility may not charge a customer a fee to conduct a pre-interconnection study for pre-certified distributed generation units up to 500 kW that export not more than 15% of the total load on a single radial feeder and contribute not more than 25% of the maximum potential short circuit current on a single radial feeder.

(2) **Distributed generation facilities for which pre-interconnection study fees may be charged.** Prior to the interconnection of a distributed generation facility not described in paragraph (1) of this subsection, a utility may charge a customer a fee to offset its costs incurred in the conduct of a pre-interconnection study. In those instances where a utility conducts an interconnection study the following shall apply:

(A) The conduct of such pre-interconnection study shall take no more than four weeks;

(B) A utility shall prepare written reports of the study findings and make them available to the customer;

(C) The study shall consider both the costs incurred and the benefits realized as a result of the interconnection of distributed generation to the company's utility system; and

(D) The customer shall receive an estimate of the study cost before the utility initiates the study.

(h) **Network interconnection of distributed generation.** Certain aspects of secondary network systems create technical difficulties that may make interconnection more costly to implement. In instances where customers request interconnection to a secondary network system, the utility and the customer shall use best reasonable efforts to complete the interconnection and the utility shall utilize the following guidelines:

(1) A utility shall approve applications for distributed generation facilities that use inverter-based protective functions unless total distributed generation (including the new facility) on affected feeders represents more than 25% of the total load of the secondary network under consideration.

(2) A utility shall approve applications for other on-site generation facilities whose total generation is less than the local customer's load unless total distributed generation (including the new facility) on affected feeders represents more than 25% of the total load of the secondary network under consideration.

(3) A utility may postpone processing an application for an individual distributed generation facility under this section if the total existing distributed generation on the targeted feeder represents more than 25% of the total load of the secondary network under consideration. If that is the case, the utility should conduct interconnection and network studies to determine whether, and in what amount, additional distributed generation facilities can be safely added to the feeder or accommodated in some other fashion. These studies should be completed within six weeks, and application processing should then resume.

(4) A utility may reject applications for a distributed generation facility under this section if the utility can demonstrate specific reliability or safety reasons why the distributed generation should not be interconnected at the requested site. However, in such cases the utility shall work with the customer to attempt to resolve such problems to their mutual satisfaction.

(5) A utility shall make all reasonable efforts to seek methods to safely and reliably interconnect distributed generation facilities that will export power. This may include switching service to a radial feed if practical and if acceptable to the customer.

(i) **Pre-Interconnection studies for network interconnection of distributed generation.** Prior to charging a pre-interconnection study fee for a network interconnection of distributed generation, a utility shall first advise the customer of the potential problems associated with interconnection of distributed generation with its network system. For potential interconnections to network systems there shall be no pre-interconnection study fee assessed for a facility with inverter systems under 20 kW. For all other facilities the utility may charge the customer a fee to offset its costs incurred in the conduct of the pre-interconnection study. In those instances where a utility conducts an interconnection study, the following shall apply:

(1) The conduct of such pre-interconnection studies shall take no more than four weeks;

(2) A utility shall prepare written reports of the study findings and make them available to the customer;

(3) The studies shall consider both the costs incurred and the benefits realized as a result of the interconnection of distributed generation to the utility's system; and

(4) The customer shall receive an estimate of the study cost before the utility initiates the study.

(j) **Communications concerning proposed distributed generation projects.** In the course of processing applications for interconnection and parallel operation and in the conduct of pre-interconnection studies, customers shall provide the utility detailed information concerning proposed distributed generation facilities. Such communications concerning the nature of proposed distributed generation facilities shall be made subject to the terms of §25.84 of this title (Relating to Annual Reporting of Affiliate Transactions for Electric Utilities), §25.272 of this title (Relating to Code of Conduct for Electric Utilities and their Affiliates), and §25.273 (Relating to Contracts between Electric Utilities and their Competitive Affiliates). A utility and its affiliates shall not use such knowledge of proposed distributed generation projects submitted to it for interconnection or study to prepare competing proposals to the customer that offer either discounted rates in return for not installing the distributed generation, or offer competing distributed generation projects.

(k) **Equipment pre-certification**.

(1) **Entities performing pre-certification.** The commission may approve one or more entities that shall pre-certify equipment as defined pursuant to this section.

(2) **Standards for entities performing pre-certification.** Testing organizations and/or facilities capable of analyzing the function, control, and protective systems of distributed generation units may request to be certified as testing organizations.

(3) **Effect of pre-certification.** Distributed generation units which are certified to be in compliance by an approved testing facility or organization as described in this subsection shall be installed on a company utility system in accordance with an approved interconnection control and protection scheme without further review of their design by the utility.

(l) **Designation of utility contact persons for matters relating to distributed generation interconnection.**

(1) Each electric utility shall designate a person or persons who will serve as the utility's contact for all matters related to distributed generation interconnection.

(2) Each electric utility shall identify to the commission its distributed generation contact person.

(3) Each electric utility shall provide convenient access through its internet web site to the names, telephone numbers, mailing addresses and electronic mail addresses for its distributed generation contact person.

(m) **Time periods for processing applications for interconnection with the utility system.** In order to apply for interconnection the customer shall provide the utility a completed application for interconnection and parallel operation with the utility system. The interconnection of distributed generation to the utility system shall take place within the following schedule:

(1) For a facility with pre-certified equipment, interconnection shall take place within four weeks of the utility's receipt of a completed interconnection application.

(2) For other facilities, interconnection shall take place within six weeks of the utility's receipt of a completed application.

(3) If interconnection of a particular facility will require substantial capital upgrades to the utility system, the company shall provide the customer an estimate of the schedule and customer's cost for the upgrade. If the customer desires to proceed with the upgrade, the customer and the company will enter into a contract for the completion of the upgrade. The interconnection shall take place no later than two weeks following the completion of such upgrades. The utility shall employ best reasonable efforts to complete such system upgrades in the shortest time reasonably practical.

(4) A utility shall use best reasonable efforts to interconnect facilities within the time frames described in this subsection. If in a particular instance, a utility determines that it can not interconnect a facility within the time frames stated in this subsection, it will notify the applicant in writing of that fact. The notification will

identify the reason or reasons interconnection could not be performed in accordance with the schedule and provide an estimated date for interconnection.

(5) All applications for interconnection and parallel operation of distributed generation shall be processed by the utility in a non-discriminatory manner. Applications will be processed in the order that they are received. It is recognized that certain applications may require minor modifications while they are being reviewed by the utility. Such minor modifications to a pending application shall not require that it be considered incomplete and treated as a new or separate application.

(n) **Reporting requirements.** Each electric utility shall maintain records concerning applications received for interconnection and parallel operation of distributed generation. Such records will include the date each application is received, documents generated in the course of processing each application, correspondence regarding each application, and the final disposition of each application. By March 30 of each year, every electric utility shall file with the commission a distributed generation interconnection report for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system. The report shall list the new distributed generation facilities interconnected with the system since the previous year' report, any distributed generation facilities no longer interconnected with the utility's system since the previous report, the capacity of each facility, and the feeder or other point on the company's utility system where the facility is connected. The annual report shall also identify all applications for interconnection received during the previous one-year period, and the disposition of such applications.

(o) **Interconnection disputes.** Complaints relating to interconnection disputes under this section shall be handled in an expeditious manner pursuant to § 22.242 (relating to complaints). In instances where informal dispute resolution is sought, complaints shall be presented to the Office of Regulatory Affairs. The Office of Regulatory Affairs shall attempt to informally resolve complaints within 20 business days of the date of receipt of the complaint. Unresolved complaints shall be presented to the Commission at the next available open meeting.

§25.212. Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation.

(a) **Purpose.** The purpose of this section is to describe the requirements and procedures for safe and effective connection and operation of distributed generation.

(1) A customer may operate 60 Hertz (Hz), three-phase or single-phase generating equipment, whether qualifying facility (QF) or non-QF, in parallel with the utility system pursuant to an interconnection agreement, provided that the equipment meets or exceeds the requirements of this section.

(2) This section describes typical interconnection requirements. Certain specific interconnection locations and conditions may require the installation and use of more sophisticated protective devices and operating schemes, especially when the facility is exporting power to the utility system.

(3) If the utility concludes that an application for parallel operation describes facilities that may require additional devices and operating schemes, the utility shall make those additional requirements known to the customer at the time the interconnection studies are completed.

(4) Where the application of the technical requirements set forth in this section appears inappropriate for a specific facility, the customer and utility may agree to different requirements, or a party may petition the commission for a good cause exception, after making every reasonable effort to resolve all issues between the parties.

(b) **General interconnection and protection requirements.**

(1) The customer's generation and interconnection installation must meet all applicable national, state, and local construction and safety codes.

(2) The customer's generator shall be equipped with protective hardware and software designed to prevent the generator from being connected to a de-energized circuit owned by the utility.

(3) The customer's generator shall be equipped with the necessary protective hardware and software designed to prevent connection or parallel operation of the

generating equipment with the utility system unless the utility system service voltage and frequency is of normal magnitude.

(4) Pre-certified equipment may be installed on a company's utility systems in accordance with an approved interconnection control and protection scheme without further review of their design by the utility. When the customer is exporting to the utility system using pre-certified equipment, the protective settings and operations shall be those specified by the utility.

(5) The customer will be responsible for protecting its generating equipment in such a manner that utility system outages, short circuits or other disturbances including zero sequence currents and ferroresonant over-voltages do not damage the customer's generating equipment. The customer's protective equipment shall also prevent unnecessary tripping of the utility system breakers that would affect the utility system's capability of providing reliable service to other customers.

(6) For facilities greater than two megawatts (MW), the utility may require that a communication channel be provided by the customer to provide communication between the utility and the customer's facility. The channel may be a leased telephone circuit, power line carrier, pilot wire circuit, microwave, or other mutually agreed upon medium.

(7) Circuit breakers or other interrupting devices at the point of common coupling must be capable of interrupting maximum available fault current. Facilities larger than two MW and exporting to the utility system shall have a redundant circuit breaker unless a listed device suitable for the rated application is used.

(8) The customer will furnish and install a manual disconnect device that has a visual break that is appropriate to the voltage level (a disconnect switch, a draw-out breaker, or fuse block), and is accessible to the utility personnel, and capable of being locked in the open position. The customer shall follow the utility's switching, clearance, tagging, and locking procedures, which the utility shall provide for the customer.

(c) **Prevention of interference.** To eliminate undesirable interference caused by operation of the customer's generating equipment, the customer's generator shall meet the following criteria:

(1) **Voltage.** The customer will operate its generating equipment in such a manner that the voltage levels on the utility system are in the same range as if the generating equipment were not connected to the utility's system. The customer shall provide an automatic method of disconnecting the generating equipment from the utility system if a sustained voltage deviation in excess of +5.0 % or –10% from nominal voltage persists for more than 30 seconds, or a deviation in excess of +10% or –30% from nominal voltage persists for more than ten cycles. The customer may reconnect when the utility system voltage and frequency return to normal range and the system is stabilized.

(2) **Flicker.** The customer's equipment shall not cause excessive voltage flicker on the utility system. This flicker shall not exceed 3.0% voltage dip, in accordance

with Institute of Electrical and Electronics Engineers (IEEE) 519 as measured at the point of common coupling.

(3) **Frequency**. The operating frequency of the customer's generating equipment shall not deviate more than +0.5 Hertz (Hz) or –0.7 Hz from a 60 Hz base. The customer shall automatically disconnect the generating equipment from the utility system within 15 cycles if this frequency tolerance cannot be maintained. The customer may reconnect when the utility system voltage and frequency return to normal range and the system is stabilized.

(4) **Harmonics.** In accordance with IEEE 519 the total harmonic distortion (THD) voltage shall not exceed 5.0% of the fundamental 60 Hz frequency nor 3.0% of the fundamental frequency for any individual harmonic when measured at the point of common coupling with the utility system.

(5) **Fault and line clearing.** The customer shall automatically disconnect from the utility system within ten cycles if the voltage on one or more phases falls below -30% of nominal voltage on the utility system serving the customer premises. This disconnect timing also ensures that the generator is disconnected from the utility system prior to automatic re-close of breakers. The customer may reconnect when the utility system voltage and frequency return to normal range and the system is stabilized. To enhance reliability and safety and with the utility's approval, the customer may employ a modified relay scheme with delayed tripping or blocking using communications equipment between customer and company.

(d) **Control, protection and safety equipment requirements specific to single phase generators of 50 kilowatts (kW) or less connected to the utility's system.** Exporting to the utility system may require additional operational or protection devices and will require coordination of operations with the host utility. The necessary control, protection, and safety equipment specific to single-phase generators of 50 kW or less connected to secondary or primary systems include an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a synchronizing check for synchronous and other types of generators with stand-alone capability.

(e) **Control, protection and safety equipment requirements specific to three-phase synchronous generators, induction generators, and inverter systems.** This subsection specifies the control, protection, and safety equipment requirements specific to three phase synchronous generators, induction generators, and inverter systems. Exporting to the utility system may require additional operational or protection devices and will require coordination of operations with the utility.

(1) **Three phase synchronous generators.** The customer's generator circuit breakers shall be three-phase devices with electronic or electromechanical control. The customer is solely responsible for properly synchronizing its generator with the utility. The excitation system response ratio shall not be less than 0.5. The generator's excitation system(s) shall conform, as near as reasonably achievable, to the field voltage versus time criteria specified in American National Standards

Institute Standard C50.13-1989 in order to permit adequate field forcing during transient conditions. For generating systems greater than two MW the customer shall maintain the automatic voltage regulator (AVR) of each generating unit in service and operable at all times. If the AVR is removed from service for maintenance or repair, the utility's dispatching office shall be notified.

(2) **Three-phase induction generators and inverter systems.** Induction generation may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured on the utility system side at the point of common coupling is within the visible flicker stated in subsection (c)(2) of this section. Otherwise, the customer may be required to install hardware or employ other techniques to bring voltage fluctuations to acceptable levels. Line-commutated inverters do not require synchronizing equipment. Self-commutated inverters whether of the utility-interactive type or stand-alone type shall be used in parallel with the utility system only with synchronizing equipment. Direct-current generation shall not be operated in parallel with the utility system.

(3) **Protective function requirements.** The protective function requirements for three phase facilities of different size and technology are listed below.

(A) Facilities rated ten kilowatts (kW) or less must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a manual or automatic synchronizing check (for facilities with stand alone capability).

(B) Facilities rated in excess of 10 kW but not more than 500 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, a manual or automatic synchronizing check (for facilities with stand alone capability), either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, and reverse power sensing if the facility is not exporting (unless the generator is less than the minimum load of the customer).

(C) Facilities rated more than 500 kW but not more than 2,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, an automatic synchronizing check (for facilities with stand alone capability) and reverse power sensing if the facility is not exporting (unless the facility is less than the minimum load of the customer). If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility.

(D) Facilities rated more than 2,000 kW but not more than 10,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, an automatic synchronizing check and AVR for facilities with stand alone capability, and reverse power sensing if the facility is not exporting (unless the facility is less than the minimum load of the customer). If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility. A telemetry/transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

(f) **Facilities not identified.** In the event that standards for a specific unit or facility are not set out in this section, the company and customer may interconnect a facility using mutually agreed upon technical standards.

(g) **Requirements specific to a facility paralleling for sixty cycles or less (closed transition switching).** The protective devices required for facilities ten MW or less which parallel with the utility system for 60 cycles or less are an interconnect disconnect device, a generator disconnect device, an automatic synchronizing check for generators with stand alone capability, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and either a ground over-voltage trip or a ground over-current trip depending on the grounding system, if required by the utility.

(h) **Inspection and start-up testing.** The customer shall provide the utility with notice at least two weeks before the initial energizing and start-up testing of the customer's generating equipment and the utility may witness the testing of any equipment and protective systems associated with the interconnection. The customer shall revise and re-submit the application with information reflecting any proposed modification that may affect the safe and reliable operation of the utility system.

(i) **Site testing and commissioning.** Testing of protection systems shall include procedures to functionally test all protective elements of the system up to and including tripping of the generator and interconnection point. Testing will verify all protective set points and relay/breaker trip timing. The utility may witness the testing of installed switchgear, protection systems, and generator. The customer is responsible for routine maintenance of the generator and control and protective equipment. The customer will maintain records of such maintenance activities, which the utility may review at reasonable times. For generation systems greater than 500 kW, a log of generator operations shall be kept. At a minimum, the log shall include the date, generator time on, and generator time off, and megawatt and megavar output. The utility may review such logs at reasonable times.

(j) **Metering.** Consistent with Chapter 25, Subchapter F of this title (relating to Metering), the utility may supply, own, and maintain all necessary meters and associated equipment to record energy purchases by the customer and energy exports to the utility system. The customer shall supply at no cost to the utility a suitable location on its premises for the installation of the utility's meters and other equipment. If metering at the generator is required in such applications, metering that is part of the generator control package will be considered sufficient if it meets all the measurements criteria that would be required by a separate stand alone meter.

This agency hereby certifies that the rules, as adopted, have been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that rule §25.211 relating to Interconnection of Distributed Generation (DG) and §25.212 relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation are hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 23rd DAY OF NOVEMBER 1999.

PUBLIC UTILITY COMMISSION OF TEXAS

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Chairman Pat Wood, III

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Commissioner Judy Walsh

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Commissioner Brett A. Perlman